COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

	)	
KeySpan Energy Delivery New England	)	**D.T.E. 04-62**
Petition to Consolidate Cost of Gas	)	
Adjustment Clauses and Tariffs	)	
	)	

INITIAL BRIEF OF THE ATTORNEY GENERAL

Respectfully submitted,

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I. INTRODUCTION

This case concerns a Petition ("Petition") by Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial") and Essex Gas Company ("Essex") (together, the "Companies"), operating as KeySpan Energy Delivery New England ("KeySpan" or the "Company"), for Department approval of a consolidated Cost of Gas Adjustment Clause ("CGA"), a consolidated Local Distribution Adjustment Clause ("LDAC"), a consolidated Distribution Terms and Conditions, and standardized rate tariff formats for all customer classes.

II. PROCEDURAL HISTORY

On June 18, 2004, pursuant to 220 C.M.R. 5.00 *et seq*. and 6.00 *et seq*., KeySpan filed its Petition with the Department. On July 7, 2004, the Department conducted a public hearing and a procedural conference to establish a schedule for discovery, hearings and briefs.

The Department conducted an evidentiary hearing on August 26, 2004. During the evidentiary hearing, KeySpan presented two witnesses to testify in support of its proposal, Elizabeth D. Arangio, Director of Gas Supply Planning for KeySpan, and Ann E. Leary, Manager of Rates for KeySpan.

III. THE COMPANY'S PROPOSAL

KeySpan is asking for Department approval to consolidate the CGA, the LDAC and the Distribution Terms and Conditions for Boston Gas, Essex and Colonial. The CGA factor is designed to recover costs that the Company incurs to purchase, transport, store and finance natural gas for its customers. Exh. KED/EDA-1, p. 4. Currently, the CGA factors charged to the customers of each of the three companies within KeySpan are calculated independently based on different CGA clauses and historical resource portfolio costs. *Id.*, p.5. The LDAC is designed to recover costs associated with transition costs, demand-side management ("DSM") programs, environmental response costs, pension and retirement-related costs, certain costs associated with the acquisition of Colonial, and costs related to the unbundling of gas activities. Exh. KED/AEL-1, p. 18.

KeySpan has modeled the proposed consolidated CGA and LDAC tariffs on the existing Boston Gas CGA and LDAC tariffs. *Id.*, p. 15. The Company has calculated the proposed consolidated CGA tariff by pooling the costs associated with a consolidated resource portfolio and charging a single price to all KeySpan customers.[1] Exh. KED/EDA-1, pp. 33-34. The proposed consolidated LDAC tariff consolidates components including (1) transition costs, (2) DSM program costs, (3) unbundling costs and (4) credits for imbalance penalties collected from competitive suppliers. Exh. KED/AEL-1, p. 17. Individual Company components will be maintained for remediation costs, pension costs and exogenous costs. *Id.*, p. 18.

[1] Because bad debt costs, a separate element of the CGA, are based on factors established in each companies' rate cases, the Company proposes to retain individual bad debt factors. Exh. KED/AEL-1, p. 10.

According to KeySpan, as the result of its merger with Eastern Enterprises, its resource planning activities for Boston Gas, Colonial and Essex are now fully integrated and it uses all the resources within the gas portfolio interchangeably to meet the combined customer requirements for its entire service territory. *See* Exh. KED/EDA-1 and Exh. KED/AEL-1. The Company claims that the consolidation of the resource portfolio has created a mismatch between (1) the costs recovered from customers though the CGA, which is based on the ownership of resource contracts; and (2) the costs and benefits associated with the provision of gas service using the restructured portfolio. Exh. KED/EDA-1, p. 8. The Company proposes to correct this mismatch by pooling the demand charges, local production and storage costs and commodity charges associated with the consolidated portfolio and establishing a uniform CGA for KeySpan customers. *Id*. The Company claims that this proposal aligns resource use with cost recovery, so that the price charged to customers appropriately distributes the costs and benefits associated with the consolidated resource portfolio. *Id*.

IV. STANDARD OF REVIEW

The Department, after reviewing the propriety of rates under G.L. c. 164, §94, sets rates that are "just and reasonable." *Attorney General, et al. v. Department of Telecommunications and Energy, et al.* 438 Mass. 256, 264, n.13 (2002). This includes rates charged to customers under cost adjustment clauses. *See Consumers Organization For Fair Energy Equality, Inc. v. Department of Public Utilities*, 398 Mass. 599, p. 608 (1975). Although the fluctuations in cost adjustment clauses may not be subject to a rate proceeding under G.L. c. 164, §94, the Department must scrutinize any proposed changes to the formulas of the cost adjustment clauses. *Id*., p. 606.

V. ARGUMENT

The Department should reject the Company's Petition because the Company has failed to establish that the rates resulting from the proposed consolidation would be just and reasonable. The Company's proposed rate consolidation (1) overcharges customers through the double recovery of costs; (2) eliminates the burner-tip merger savings that the Department relied on in approving the Essex and Colonial mergers; and (3) includes cash working capital allowance calculations that do not comply with Department precedents and standards. In addition, the proposal does not have composite tariffs that clearly describe the rate components for each company and how the various components flow through the rates.

A. THE COMPANY WILL OVERCHARGE ITS CUSTOMERS IF THE DEPARTMENT APPROVES THE PROPOSED CONSOLIDATION.

The Department should reject the Company's CGA consolidation proposal because it results in the double recovery of costs. The Company confirmed that at least one category of costs to be recovered through the consolidated CGA, gas acquisition costs, will be double recovered. Tr. 1, pp. 20-21. The Department does not allow a utility to recover costs twice. *See Fitchburg Gas and Electric Light Company*, D.T.E. 99-66-A (Department ordered refund with interest of costs determined to have been collected through both base rates and the CGA); *Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy*, 440 Mass. 625 (2004) (Company had illegally overcharged customers by including same category of costs in base rates and CGA); and *Wyman-Gordon Company*, D.P.U. 1669-B (1987) (Company may not collect same cost twice).

KeySpan service company employees perform all gas acquisition, planning and dispatching functions and KeySpan charges these costs to Boston Gas, Colonial and Energy North according to SEC approved allocation formulas.[2] Tr. 1, p. 26. All of Essex's costs related to gas acquisition, planning and dispatching are included in the costs allocated to Boston Gas. Exh. AG-1-16 and Tr. 1, pp. 19-20. In Boston Gas Company's recent base rate case, the Companies reallocated the 2002 (test year) gas acquisition costs for Colonial under their interpretation of the Department's order regarding incremental cost allocation. *Boston Gas Company*, D.T.E. 03-40, p. 214. The reallocation charged the Colonial costs to Boston Gas and, in turn, the costs were included in Boston Gas rates effective November 1, 2003. *Id*. Boston Gas Company customers currently are being charged gas acquisition costs in the amount of $896,198 (excluding the related cash working capital allowances). Exh. AG-1-16. Essex is recovering over $186,418 through its base rates (Exh. AG-2-2) and Colonial is recovering $985,818, half the amount through base rates and half through its CGA. Exh. AG-1-10. As a result, the Company is over recovering its gas acquisition costs - Boston Gas Company customers are currently being charged all costs incurred and Essex and Colonial customers are paying costs no longer incurred. The Company's proposal may eliminate the over recovery of only a portion of the costs, the amount related to the costs flowing through the Colonial CGA, $492,909. Exh. AG-1-4 and Exh. AG-1-3. The Company, however, has indicated that it is not proposing to adjust base rates; but

[2] There are no costs, in addition to the costs being charged to Boston Gas, being incurred by the companies for gas acquisition and dispatch. Tr. 1, p. 26. How this category of costs is recovered through rates varies. Essex recovers all of its gas acquisition and dispatch costs with the related overhead costs and working capital costs through the base rates. Exh. AG-1-9. The Company estimated that the direct costs for gas acquisition function during the 1995 test year were $182,528. Exh. AG-2-2. The related cash working capital allowance adds another $3,890 for a total of $186,418. *Id*. This is a conservative estimate of costs Essex customers currently pay because the Company is unable to identify 1995 costs booked to accounts other than account 813, Gas Supply Purchase and Acquisition costs. *Id*. Acquisition related costs would also have been booked to account 923, Outside Services. *Id*.

that it "... is not opposed to treating gas-acquisition costs in the same way that bad-debt will be treated, in that the Company could establish an individual charge for each company. If handled in this matter (sic), the charge for Essex customers would be zero." Exh. DTE-1-42. Unless the total gas acquisition costs, both the amounts in the Colonial CGA and base rates and the amount in the Essex base rates, are removed from Boston Gas costs, there will be a double recovery of gas acquisition costs. The Department should reject the Company's proposal and also require the Company to refund the over collections that have occurred since November 1, 2003, the date the Boston Gas rates became effective.

B. THE COMPANY'S PROPOSAL DOES NOT CONFORM WITH THE DEPARTMENT APPROVED COLONIAL AND ESSEX MERGER RATE PLANS.

1. THE COMPANY'S PROPOSAL WILL DENY COLONIAL AND ESSEX CUSTOMERS MERGER RELATED SAVINGS PROMISED IN THE MERGER RATE PLANS.

The Department should reject the Company's proposal because the Company, by not showing how it has achieved merger related gas cost savings, has failed to meet its burden of proof that the proposed consolidated CGA rates are just and reasonable.

It is only through the merger of Colonial Gas and Essex into Eastern Enterprises that the Company is able to propose the consolidation of tariffs and related rates. *See Eastern Enterprises and Colonial Gas Company*, D.T.E. 98-128 (1999) and *Eastern Enterprises and Essex County Gas Company*, D.T.E. 98-27 (1998). In D.T.E. 98-128 and D.T.E. 98-27, the Department approved the mergers based on the showing that the mergers were in the public interest and beneficial to the companies' customers. The customer benefits were quantified in two categories, ten year base rate freezes and "burner-tip" gas cost savings. Burner-tip savings for Essex were estimated to total $2.35 million annually for a total of $23.5 million over the ten years the merger rate plan is in effect. *Eastern Enterprises/Essex*, D.T.E. 98-27, pp. 6-7. In approving the Essex merger and ten year rate plan, the Department determined that, although the $2.35 million annual CGA savings were based on estimates, "[t]he estimates are carefully calculated and support our findings that the proposed Rate Plan will likely provide gas costs savings to Essex customers, of the magnitude projected by the Petitioners, and that these savings would be unavailable in the absence of the proposed merger."[3] *Id.*, p. 30.

For Colonial, the burner-tip savings estimates were approximately $4.00 million annually with a total of $37.00 million over the ten years of the rate plan. *Eastern Enterprises/Colonial*, D.T.E. 98-128, pp. 70-71. In approving the Colonial merger rate plan, the Department, as it had in the Essex case, evaluated each component of the $37 million gas-related savings and found that "ratepayers are likely to be better off with respect to gas costs, and certainly no worse off, than they would be absent the merger." *Id.*, pp. 73-74.

Colonial and Essex customers were promised gas cost savings in return for foregoing possible base rate reductions related to merger savings in cost categories recovered through base rates during the time not only of the base rate freeze, but also during the remaining 30 years that the acquisition premium will continue to be amortized.[4] The Company, in support of its

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[3] The Department does note in its order that "under a worst case scenario, none of the projected savings were to come to fruition, the LDAC savings [a $900,000 credit passed through to customers for two years] of this magnitude would be guaranteed to ratepayers. Such a guarantee does not exist absent the merger." *Eastern Enterprises/Essex*, D.T.E. 98-27, p. 28. The Company does not, and cannot, claim that it has experienced a worst case scenario since the Company has failed to analyze or track any of the promised savings. Exh. DTE-1-23; Exh. AG-1-15; and Tr. 1, p. 22.

[4] "...[S]hareholders will have the opportunity to recoup the remaining three-fourths of the acquisition premium and return on the cash advance after they quantify the synergies and demonstrate that the benefits of the merger equal the amount of the acquisition premium. As collection of the acquisition

proposal to combine the three companies' CGAs, clearly demonstrates that Colonial and Essex customers will immediately experience burner-tip price increases. Exh. KED/AEL-3 and Exh. AG-1-17. Consolidation of the CGAs, therefore, will harm Colonial and Essex customers by denying them promised savings as approved in the merger cases, D.T.E. 98-27 and D.T.E. 98-128.[5] The Department should reject the Company's proposal.

2. THE COMPANY HAS NOT DEMONSTRATED THAT MERGER RELATED COSTS IT SEEKS TO RECOVER ARE OFFSET BY MERGER RELATED SAVINGS.

The Department requires a Company seeking recovery of costs directly related to a merger to demonstrate merger related savings. *Mergers and Acquisitions*, D.P.U. 93-167-A, pp. 18-19 (1994); *Eastern Enterprise/Essex*, D.T.E. 98-27, p. 8; *Eastern Enterprise/Colonial*, D.T.E. 98-128, pp. 5-6. The Company's proposal, if approved, will result in the Company increasing its recovery of merger related costs. The Company has not demonstrated that there are any merger savings to offset the costs. Since the Company has failed to quantify merger savings sufficient to allow the recovery of additional merger costs, the Department should reject the proposal.

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premium and the return on the cash advance is related to the dollar amount of the benefits received by ratepayers, the Department finds that the distribution of these benefits between the ratepayers and shareholders is fair." *Eastern Enterprises/Colonial*, D.T.E. 98-128, p. 85.

[5] Although the Company does not track burner-tip savings, it apparently considers the promise of burner-tip savings as having been fulfilled. When asked whether the promised savings continued to be achieved today, Ms. Leary responded

> They were achieved in the first few years. In fact, if I recall, the first two years, we did actually have a guarantee in there. I don't recall off the top of my head what the exact amount was, but I do remember that the first two years there was a guarantee.
> Going forward, that's part of the issues that we have here today, is *we are still assigning gas costs to Essex in accordance with that merger agreement that occurred six years ago*, and the gas-supply portfolio and the dynamics have since changed.

Tr. 1, p.14. (emphasis added).

The Department has indicated that "[i]n a rate case proceeding, there is no explicit requirement that merger related savings be demonstrated, unless the petitioning utility is seeking to recover costs that are directly related to a merger, such as an acquisition premium." *Boston Gas Company*, D.T.E. 03-40, p. 202 (2003). The Company's petition for consolidated rates is a rate case as defined by statute, G.L. c. 164, §94, and regulation, 220 C.M.R. 5.00. The petition also involves the recovery of merger related costs through the incorporation of an over recovery component.

Under the Department approved merger orders, the Company has booked all gas acquisition, planning and dispatch costs to the accounts of Boston Gas Company. *See Eastern Enterprises/Essex*, D.T.E. 98-27 and *Eastern Enterprises/Colonial*, D.T.E. 98-128. The Company currently recovers all of these costs from Boston Gas Company customers through base rates and through the CGA. Tr. 1, pp. 25-27. Under the Company's proposal, when the CGAs are consolidated, the CGA portion of these costs will be recovered from the customers of all three companies, Boston, Essex and Colonial.[6] In addition, each customer will continue to pay vestigial gas acquisition, planning and dispatch costs included in the base rates of Essex and Colonial.[7] This results in the over recovery of gas acquisition, planning and dispatch costs, which then increases the ability of Colonial and Essex to offset merger costs during the base rate freeze period.[8] The Company is responsible for proving that the merger related costs Essex and

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[6] Boston Gas Company customers will continue to be the sole source for the recovery of the base rate allocation of the actual gas acquisition, planning and dispatch costs.

[7] The Companies' recovery of gas acquisition costs from customers is discussed in detail on page 5, *supra*.

[8] The Department historically has rejected any attempt by a utility to permanently benefit from over recovered costs. Most recently, the Department ordered Fitchburg Gas and Electric to refund costs that it

Colonial customers will be paying, if the Company's proposal is approved, are offset by sufficient merger savings. The Company has failed to prove this. As discussed above, the Company has not tracked or analyzed any gas cost savings promised in the merger petitions. Indeed, the Company has not provided any quantitative analysis of merger savings. The Company has only repeatedly stated that there is an inequitable allocation of costs between the companies that it believes will be resolved by the proposed rate consolidation. Exh. KED/EDA-1, p. 5 and Exh. KED/AEL-1, p. 4. Since the Company cannot demonstrate that Colonial and Essex customers are recovering merger savings at a level equal to or greater than the additional costs the Company seeks to recover from them, the Department should reject the Company's proposal.

C. THE COMPANY'S PROPOSED TARIFF CHANGES LACK SUFFICIENT SPECIFICITY.

1. THE COMPANY'S PROPOSED CASH WORKING CAPITAL ALLOWANCE METHODOLOGY INCREASES COSTS WITHOUT SUFFICIENT SUPPORTING DOCUMENTATION.

The Department should not approve the Company's proposal because the cash working capital allowance methodology increases costs without sufficient supporting documentation. The Company proposes to change the way it computes the gas cash working capital allowance. Exh. KED/AEL-1, p. 9. The cash working capital allowance represents the cost of funds (cost of capital) needed to finance gas costs from the time the Company pays for gas purchases and the time the Company receives payment from customers. *Bay State Gas Company*, D.P.U. 92-111, p. 72 (1992). The time period is based on the determination of the net lag representing the

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had been over recovering for a period in excess of ten years. *See Fitchburg Gas and Electric Light Company*, D.T.E. 99-66-A (2001).

number of days between the payment of bills and the receipt of cash payments from customers. Currently, each company has a different cash working capital allowance factor based on the cost of capital approved in each company's last base rate case and different methods of determining the net lag. The net lag currently used in Essex's CGA is 14.5 days, Colonial uses 15.3 days and Boston Gas uses 39.7 days. *See* Exh. AG-1-3. The Company claims that the significant difference between the net lag for Boston Gas and Essex is due to the use of a full year to determine the net lag for Essex where Boston Gas used two six month periods (peak and off peak). Tr. 1, pp. 30. Also, Boston Gas Company experiences a longer collection period than the two non-urban utilities. Tr. 1, pp. 30-32. The Company also attributes some of the difference between Colonial and Boston Gas to the fact that the net lag for Colonial was based on 1992 data used in Colonial's last rate case. *Id*.

The Company proposes to use Boston Gas Company's cost of capital the Department approved in D.T.E. 03-40, 9.08%, which is lower than either the Essex (10.67%) or Colonial (10.64%) costs currently incorporated in their CGAs, 10.67% and 10.64%, and to compute net lag days based on new data for the Companies. Tr. 1, pp. 30-32 and Exh. KED/AEL-1, p. 9. The Company proposes to use the new data to determine the number of days between customer billing and collection, but to base the other components of the net lag calculation, the days from the receipt of service to meter read, days form meter read to billing, and the expense payment lag, on Boston Gas Company data. *Compare* DTE-1-43 and AG-1-3, p. 13, Boston Gas CGA Form II, section F.

The Department has allowed companies to recalculate their purchased gas cash working capital allowance factors annually based on the change in purchased gas lag days. *Bay State Gas*

Company, D.P.U. 92-111, p. 73 (1992); *Colonial Gas Company,* D.P.U. 93-78-A, p. 5. The Company's proposal here, however, goes well beyond the recalculation based on a change in purchased gas lag days, it incorporates changes to all components of the allowance without any supporting study or analysis.[9]

The Company's proposal is not based on any methodology previously approved by the Department and results in significant increases in costs to Essex and Colonial customers, even with the use of the lower cost of capital, by more than doubling the cost flowing through the CGA. *See* RR-AG-2 and RR-DTE-2. Until the Companies can supply a lead lag study or another acceptable method of determining consolidated working capital requirements, the Department should reject the Company's proposal and require the Companies to continue to calculate their requirements and allowances separately for the CGAs using the Department approved method.

2. THE COMPANY'S PROPOSED TARIFF LANGUAGE IS TOO BROAD.

The Department should require the Company to refine its proposed tariff language. The Company's tariff language should be a clear statement of which CGAC allowable costs and revenues are based on the partial consolidation of rates. The Department has stated that it supports improving tariff language and that the appropriate venue for making such changes is "an open process where all potentially interested parties have the opportunity to examine proposals and offer comments." *Fitchburg Gas and Electric Light Company*, D.T.E. 02-24/25, p. 288

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[9] The Company did not provide the details of the cash working capital allowance calculations in its original filing. The Company addresses only the proposed change in the cost of capital and not the use of new net lag data and methodology. Exh. KED/AEL-1, p. 9 and DTE-1-43. The Department should not accept this type of unsupported and undocumented change.

(2002). The Attorney General welcomes the opportunity to participate in such a generic proceeding to revise model tariffs. In making the following suggested changes to the Company's proposed tariff language, the Attorney General seeks to clarify the language as it applies to the KeySpan companies and reflects their unique rate consolidation. For these reasons, the Department should not delay implementing these recommended improvements to the proposed tariffs.

The Company's CGA tariff does not clearly state which specific costs the Department allows to be included in the CGA. The Department should require the Companies' tariffs to provide sufficient information to allow interested parties to review filings and determine whether costs included conform to the Department's orders and precedents. An important component of the CGA tariffs is the definitions section. The Companies have not provided a sufficiently comprehensive set of definitions for such key cost components as (1) gas acquisition, planning and dispatch expenses; (2) reconciliation adjustment factors; (3) carrying costs, as they apply to reconciliation items, including credits for capacity release, off-system sales, and interruptible sales; (3) interim gas adjustment factor; (4) cash working capital allowance (each category should be listed); (5) capacity release (6) margin sharing;[10] (7) downstream assets; (8) non core; and (9)

[10] In this case, the Company discussed the mechanics of margin sharing, what specific categories of revenue are treated as potential shared margins, and how the revenues are flowed through the CGA and adjusted for any amounts above annual thresholds that are shared with the Company's shareholders. Tr. 1, pp. 33-34. The Company described four categories (1) capacity release; (2) off-system sales; (3) interruptible transportation; and (4) interruptible sales. The proposed combined tariff does not include separate definitions for each of these categories nor does it describe how the revenues may be shared with the Company's shareholders. In addition, the Company has indicated that it will include in its margin sharing categories the revenues that it will receive under the sharing provision of its 2004 contract with Entergy-Koch. Tr. 1, p. 40. The Entergy-Koch contract is currently before the Department for approval in docket D.T.E. 04-09. The Entergy-Koch contract contains provisions that require Entergy-Koch to split savings generated under the agreement with the Company. This provision is somewhat unique, although Berkshire Gas Company, who has a similar arrangement with BP, is

marginal cost. Other definitions need to be expanded to allow interested parties to understand how the terms are used in the CGA calculations.[11] The Company has attempted to expand the definitions section of the CGAC tariff, but needs to go further to make the tariff more customer friendly. Exh. KED/AEL-5. Unless the Company provides clear definitions in the tariffs, the Department should not approve the Company's proposed tariffs.

3. THE COMPANY MUST CORRECT ERRORS IN ITS PBOP RECONCILIATION ADJUSTMENT FACTOR BEFORE THE TARIFF GOES INTO EFFECT.

The Company must correct two errors in its proposed tariff for its Pension and Post-Retirement Benefits Other Than Pensions ("PBOPs") Reconciliation Adjustment Factor ("PRAF") before the tariff can be put into effect. The proposed tariff contains changes to many elements to the PRAF formula that are contrary to the Department's original order addressing the PBOP costs and PRAF. *See Boston Gas Company*, D.T.E. 03-40, (2003) and *Boston Gas Company*, D.T.E. 03-40-A, *Orders on Motions For Clarification by the Company and the Attorney General* (2004). The errors in the Company's formula include (1) amortization of the unamortized PBOP transition obligation over a three-year period instead of a ten-year period; and

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currently seeking Department approval to share with the Berkshire shareholders the revenues it receives from BP for both the traditional capacity management fee and the savings that the agreement requires be shared between the company and BP. *Berkshire Gas Company*, D.T.E. 04-47. To the extent the Department allows the shared savings from the operation of the Entergy-Koch agreement to be shared with Company's shareholders, this new category of margins should be defined in the Companies' tariff.

[11] Other definitions that should be expanded include (1) bad debt expense; (2) proportional responsibility allocator; (3) other supply expenses, which should be more narrowly defined based on separately defined terms for gas acquisition, planning and dispatch, local production and storage, bad debts and margin sharing; (4) cost of debt; (5) cost of equity; (6) weighted cost of capital; (7) economic benefit; and (8) therm conversion factor. The definitions for cost of debt, cost of equity and weighted cost of capital should all indicate what the Companies use for values.

(2) the provision for carrying charges twice on the Unamortized Reconciliation Deferral Pension amount.

The Department's original Order required the Company to recover its PBOPs costs through base rates, including the 10-year amortization of the transition obligation without carrying charges:

> [t]he final component of the Company's proposal regards the ten-year amortization of the $44 million PBOP transition obligation amount remaining on December 31, 1992 (Exh. KEDNE/JFB-1, at 43). According to the Company, the amortization of the PBOP transition obligation costs is currently included in its base rates (Tr. 22, at 3022-3023). The Company proposes to include this obligation in the reconciling mechanism for reasons of regulatory consistency.(id. At 3022-3023). Under this proposal, the Company would begin collecting approximately $4.4 million through the reconciling mechanism beginning on November 1, 2003 (Exh. AG-11-19, Att.).
>
> The Department finds that the PBOP transition obligation, however, is distinct from the Company's pension expense. It has a different amortization period and is proposed without carrying charges (Tr. 22, at 3022-3023). Further, the Company's (sic) proposes that its PBOP expense continue to be recovered in base rates. (*Id*. At 3023). Accordingly, the Department orders the Company to continue its PBOP and PBOP transition obligation through base rates.

Boston Gas Company, D.T.E. 03-40, pp. 312-313. Subsequently, in D.T.E. 03-40-A, the Department shifted these costs to the PRAF:

> In light of the Company's explanation of the need to include the PBOP deferrals in the annual adjustment mechanism, we agree that the mandates of FAS 71 as well as our precedent established in Boston Edison Company / Commonwealth Electric Company / Cambridge Electric Light Company / NSTAR Gas Company, D.T.E. 03-47-A (2003) (allowing a pension and PBOP annual adjustment mechanism) make it appropriate to include PBOP deferrals in the Company's annual adjustment mechanism. Accordingly, the Company's request for reconsideration is granted with respect to the inclusion of the PBOP deferrals in the annual

> adjustment mechanism.

Boston Gas Company, D.T.E. 03-40-A, p. 7.

In D.T.E. 03-40-A, the Department simply moved the cost recovery from base rates to the reconciliation mechanism. *Id*. The Department did not order the Company to modify or rescind the amounts of the PBOPs costs to be recovered in any year; the Department only changed the manner in which those costs are recovered - through the new PRAF instead of base rates. *Id*. The Company's own language in the proposed tariff, Section 6.10, defines the PRAF formula and Post Retirement Benefits Other Than Pensions as

> the costs associated with PBOP as determined by SFAS-106 and as approved by the Department, and ***the PBOP transition obligation amortized over ten years.***

Exh. KED/AEL-9, p. 6 (emphasis added). The Company, however, includes a component "APDA" in the PRAF formula itself:

> APDA = The Accumulated PBOP Deferral Amortization is ***the amount of Boston Gas Company's unamortized PBOP transition obligation outstanding on December 31, Year t, amortized over a THREE year period***. The APDA will be a fixed amount recovered over a THREE-year period beginning on November 1, YEAR t + 1 and ending October 31, Year t + 3.

Exh. KED/AEL-9, p. 15 (emphasis added). Thus, although the Department ordered, and the Company recognized, that the PBOPs transition obligation should be amortized over 10 years, the formula provides for a much shorter three-year period. The annual cost to customers of this error is more than $10 million per year:

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\begin{aligned}
\$10{,}266{,}667 &= \$44{,}000{,}000 / 3 \text{ years} - \$44{,}000{,}000 / 10 \text{ years} \\
&= \$14{,}666{,}667 - \$4{,}400{,}000 \\
&= \$10{,}266{,}667.
\end{aligned}
$$

Boston Gas Company, D.T.E. 03-40, pp. 312-313. The Department should order the Company to correct this clear mistake in the Company's proposed tariff that will unfairly add over $10 million to customers annual bills.

The Company's formula also allows the Company to recover twice the carrying charges on unamortized reconciliation deferred balances. The PRAF formula provides carrying charges on two components, the URD and the APBOP. *See* Exh. KED/AEL-9. The URD is defined as

> URD_t = The Unamortized Reconciliation Deferral Pension is the amount of the Pension Reconciliation Deferral not yet included in distribution rates.

Exh. KED/AEL-9, p. 14. The URD term, therefore, provides carrying charges on deferred pension amounts. Furthermore, the APBOP is defined as

> APBOP = The unamortized Reconciliation Deferral not yet include in distribution rates.

Id., p. 15.

In addition, the Company's language in the proposed Tariff, Section 6.10, defines the term "Reconciliation Deferral" as

> Reconciliation Deferral is the ***difference between (1) the total pension*** and PBOP expense amounts included in Boston Gas Company's base rates; ***and (2) the total expense amounts booked by Boston Gas Company in the Prior Year in accordance with the requirements of FAS 87*** and FAS 106.

Exh. KED/AEL-9, p. 6 (emphasis added).

Since the proposed second tariff term, the APBOP, includes both the pension and PBOPs deferred amounts, and the proposed first tariff term, the URD, includes pension deferrals by themselves, the Company, through the proposed formula, is seeking to double-recover carrying charges on the pension deferrals. The Department can eliminate this double-recovery by simply removing the URD term from the formula in its entirety, which will ensure that the Company recovers those carrying charges only once on the APBOP.

Finally, the Company has not provided interest on the Past Period Reconciliation Amounts as the other utilities with PRAF filings have. Both NSTAR and Fitchburg Gas and Electric Light Company have requested that interest on the Past Period Reconciliation Amounts be debited / credited to the PRAF at the prime rate computed in accordance with 220 C.M.R. § 6.08 (2). See *Commonwealth Electric Company, Cambridge Electric Light Company, and Boston Edison Company*, D.T.E. 03-47, M.D.T.E. 112, Sheet No. 3, M.D.T.E. 209, Sheet No. 3, and M.D.T.E. 109, Sheet No. 3, respectively (2003) and *Fitchburg Gas and Electric Light Company*, D.T.E. 04-48, Exh. FGE-1, Tariffs M.D.T.E. No. 112, Sheet No. 3 and No. 119, Sheet No.3 (2004). The Department should direct the Company to include interest on over / under recoveries so that the Company does not profit unjustly from over-collections from its customers.

The Department, therefore, should order the Company to correct the proposed PRAF formula by (1) changing the amortization of the transition obligation from three to ten years; (2) removing the URD term in its entirety from the formula to ensure that there is no double-recovery of carrying charges on pension reconciliation deferral balances; and (3) adding an interest provision on the Past Period Reconciliation Amounts.

VI. CONCLUSION

WHEREFORE, for all of these reasons, the Attorney General requests that the Department reject the Company's Petition.

Respectfully submitted,

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